BEFORE THE

ILLINOIS COMMERCE COMMISSION

DOCKET NO. 05-0738

PREPARED REBUTTAL TESTIMONY

OF

MARK A. MARTIN

On Behalf of

ATMOS ENERGY CORPORATION

I. POSITION AND QUALIFICATIONS

Q. Please state your name, position and business address.

A. Mark A. Martin, Manager, Regional Gas Supply Operations, Atmos Energy Corporation (the "Company"), 377 Riverside Drive, Suite 201, Franklin, TN 37064-5393.

Q. Did you prepare direct testimony filed in this proceeding?

A. Yes. My direct testimony already describes my educational and professional background, as well as my responsibilities when I was Director, Regional Gas Supply Operations for the East Region of Atmos Energy Services ("AES"), an affiliate of the Company.

Q. Have any organizational changes occurred since the filing of your direct testimony?

A. Yes. Effective January 1, 2007, the gas supply procurement and management functions for all of the Company's utility operations, including Illinois, and which had previously been performed by AES, were consolidated into the Company's Shared Services under the Company's Vice President of Gas Supply and Services.

My scope of gas supply responsibilities remained essentially the same and currently encompasses several states in which the Company has regulated utility operations, including Illinois.

Q. Do your responsibilities also include preparing gas supply requests for proposal, negotiating related agreements and oversight of capacity and storage needs relating to supply for the Company's Illinois distribution systems?

A. Yes. Working in conjunction with several departments and personnel within the Company, I oversee the preparation and receipt of the requests for proposal (RFP) for the Company's gas supply and capacity requirements in Illinois, managing the supply and capacity needs of the distribution system and negotiation of supply and capacity agreements.

Q. What is the purpose of your rebuttal testimony?

A. Within this Docket, the Commission Staff and Atmos exchanged over 170 data requests and responses. The Staff's direct testimony was the result of this data request process. Based on the conclusions of the Staff witnesses, the Company believes it did not clearly communicate the facts and information regarding the circumstances and decisions surrounding the natural gas supply and supporting contracts for the Harrisburg operating area. The objective of this rebuttal testimony is to present in a clear and concise manner the facts and information regarding the Company's natural gas supply, specifically for the Harrisburg operating area, in order to facilitate a more complete understanding of the Company's decisions and why those decisions were prudent.

As a preface to the discussion regarding the Staff's specific issues, I will discuss my understanding of the gas cost reconciliation process in Illinois. I will also provide a descrip-

tion of the Company's gas distribution system in Illinois, such as the communities served, number of customers, proximity to other systems or parties that enable deliverability of gas supply and typical load requirements.

I will then describe the Company's gas supply planning process including an overview of design day analysis and forecasts and the evaluation of existing and potential capacity and storage needs.

I will also describe the Company's process relating to development and distribution of requests for proposals for gas supply, receipt and analysis of suppliers' proposals and what occurs after a successful bidder has been selected.

Finally, I will address Staff's specific issues as discussed in their direct testimony in this docket, including the impact of the termination of the Egyptian Storage ("Egyptian") contract and the contractual elements of the Company's agreement with its affiliate, Atmos Energy Marketing, LLC ("AEM").

II. GAS RECONCILIATION PROCESS

Q. Are you familiar with the standard the Commission uses to determine prudence within the context of a gas cost reconciliation proceeding?

A. Yes. Staff witness Dennis Andersen recites the applicable standard on page 4 of his direct testimony. I note that the cite by Mr. Andersen from a prior Commission docket makes two very important points.

Q. What are those points?

A. The first point is that, for purposes of determining whether a judgment by the Company was prudently made, only those facts available at the time the judgment was exercised can be considered. In other words, imprudence can result only if a utility manager made

a decision or took action that was unreasonable based on the facts known to the manager at the time of that decision. A critique of the Company's decisions using hindsight analysis is not proper.

The second important point is that the prudence standard recognizes that reasonable persons can have honest differences of opinion, and that imprudence cannot be established simply by the substitution of a Staff witness' judgment in place of the Company's. A utility's decision is prudent if it was within the range of decisions reasonable persons might have made.

The Company will show in this testimony that each decision it made in 2005 was fully justified and to the benefit of its Illinois customers.

III. THE COMPANY'S ILLINOIS SYSTEM

Q. Are you familiar with the Company's gas distribution system in Illinois?

A. Yes. The Company's distribution system in Illinois provides gas service to six operating areas comprised of Virden, Vandalia, Harrisburg, Metropolis, Salem and St. Elmo. Additional cities and towns within these six operating areas served by the Company include Alma, Altamont, Beecher City, Brookport, Brownstown, Carrier Mills, Cowden, Eldorado, Farina, Farmersville, Galatia, Girard, Huey, Iuka, Joppa, Kinmundy, Middletown, Muddy, New Holland, Releigh, St. Peter, Thayer, Waggoner and Xenia. Through its Illinois distribution systems, the Company serves approximately 24,000 customers.

Q. How does the Company receive gas supply for its distribution systems?

A. Each of the six operating areas is served by an interstate pipeline as follows:

- Virden – Panhandle Eastern Pipe Line Company
- Vandalia – Natural Gas Pipeline Company of America

- Harrisburg – Texas Eastern Transmission Corporation (TETCO)
- Metropolis – Trunkline Gas Company
- Salem – Mississippi River Transmission Corporation, Natural Gas Pipeline Company of America and Trunkline Gas Company
- St. Elmo – Natural Gas Pipeline Company of America

The Company's gas supply for these operating areas is received at agreed upon receipt points, typically city gates.

Q. Are the Company's gas supply purchases for all of these operating areas during the review period disputed by Staff in this proceeding?

A. No. Staff has only called into question the Company's decisions made with respect to gas supply procurement for the Harrisburg operating area.

IV. THE HARRISBURG AREA OPERATING SYSTEM

Q. Which interstate or intrastate pipelines serve the Harrisburg operating area?

A. TETCO is the only pipeline that is geographically proximate to the Company's Harrisburg operating area.

Q. Does the Company hold any firm capacity on TETCO or have an interruptible transportation contract with TETCO for its Harrisburg operating area?

A. The Company holds no firm capacity because TETCO's firm capacity is fully subscribed and has been for many years. The Company has not held any firm capacity on the TETCO pipeline system for over six years. Currently, the Company has interruptible transportation (IT) service agreements with TETCO. The Company has maintained two IT contracts with TETCO since February 1994, and they have been effective since that date. Copies of those contracts are attached as Exhibit MM-R-1 and Exhibit MM-R-2.

Q. What are the primary differences between firm and interruptible pipeline transportation service?

A. Firm service means that, subject to contractual and applicable pipeline tariff terms, the capacity, up to the contractually stated maximum daily quantity (MDQ), is "on call" at the need of the capacity holder without service interruption. Firm service requires the payment of monthly demand charges in order for the pipeline to hold that capacity open and these charges are incurred regardless of whether the capacity is actually used. On the other hand, interruptible service means that the pipeline will provide transportation service for volumes up to a contractually stated MDQ if there is any available capacity on the pipe after satisfying the requirements of firm capacity holders. Interruptible service provides no guarantees that transportation capacity will be available when it is needed. As a result, interruptible transportation only requires the payment of fees to the pipeline when capacity is actually available and transportation service is actually provided.

Q. For how many gas receipt point meters is the Harrisburg operating area served by TETCO and where are those meters located?

A. The Harrisburg operating area is metered from two locations, Harrisburg and Galatia. These two metering points have been utilized for as long as the Harrisburg area has been served by both the Company and United Cities Gas Company, the Company's corporate predecessor in Illinois. I have found nomination summaries dating back to November 1999 where the nominations are separated between Harrisburg (70039) and Galatia (71401). It was also stated in the capacity contracts we once held that there were two distinct receipt meters. In addition, in the contract addendum with AEM for the 2004/2005 season, attached hereto as Exhibit MM-R-3, both the Harrisburg and Galatia meters are

designated as separate nomination points. The same holds true for the contract addendum with AEM for the 2003/2004 season, attached hereto as Exhibit MM-R-4.

Q. Has the Company been able to acquire any firm capacity on TETCO?

A. Not on any long-term or continuous basis.

Q. Does the Company hold any storage capacity that has been used to serve the Harrisburg operating area?

A. Until May 1, 2005, the Company held storage capacity in three storage fields – Egyptian, Wiseman and Ellis. Egyptian is owned by Egyptian Gas Storage Company. Wiseman and Ellis are owned by Gallagher Drilling.

V. STORAGE CAPACITY FOR THE HARRISBURG OPERATING AREA

Q. Please describe the location and utilization of the three storage fields that made up the storage capacity for the Harrisburg operating area in 2005.

A. Egyptian is located downstream of the Company's city gate on the TETCO system and the other two are located behind the Company's city gate. The Company has no pipeline storage which can be used to balance the system.

Q. Why is the location of these fields important?

A. Location can impact deliverability. Because Wiseman and Ellis are behind the Company's city gate, subject to operational considerations and applicable contract terms, these two fields could allow the Company to deliver gas withdrawn from storage directly into the Company's distribution system. Pipeline capacity is not needed for Wiseman and Ellis. On the other hand, the location of the Egyptian storage field downstream on the TETCO system in the Consumers Gas Company area meant that the Company had to

have a backhaul arrangement in place with TETCO. Therefore, Egyptian storage capacity was dependent on the use of the transmission pipeline system.

Q. Could the Company use any of these storage facilities for system balancing?

A. No. Wiseman, Ellis, and Egyptian were and are all nominated storage services and could not and cannot be used to balance the system. The storage gas available to the Harrisburg operating area from a field operations standpoint could only be used as a function of the area's nomination process over a monthly timeframe. As a result the Company could not pull from storage one day and inject into storage the next day, which would be the only type of storage that could be utilized for system balancing.

Q. How did the Company historically guaranty deliverability of its gas stored in the Egyptian storage field?

A. Through a methodology known as displacement. For many years the Company's gas supplier was the same as the gas supplier for Consumers Gas Company. AEM (the supplier for both LDC's) held an exchange agreement with Consumers Gas that facilitated its ability to take a certain volume of the Company's gas stored in Egyptian and "exchange" that volume for an equivalent volume of gas from Consumers that AEM could cause to be delivered to the Company's Harrisburg operating area city gate. The storage gas "exchange" was considered firm gas delivery to the Harrisburg operating area.

Q. What happened in 2004?

A. Consumers Gas Company terminated its exchange agreement with AEM in conjunction with taking its gas supply from another gas supplier and, as a result, AEM was no longer able to guarantee delivery of any of the Company's storage volumes in Egyptian on a firm basis. Accordingly, the Company gave notice to Egyptian of its intent to terminate

its storage agreement in August 2004 and did terminate the agreement effective May 1, 2005.

Q. What were the facts behind the decision to cancel the Egyptian storage agreement?

A. The facts supporting the decision to cancel the Egyptian storage agreement were as follows: (1) TETCO is the only interstate pipeline serving the Company's Harrisburg operating system; (2) TETCO was and is fully subscribed and no firm capacity was or is available through TETCO; (3) without the Consumers exchange agreement, there was no way for the Company to receive firm deliveries of storage gas from Egyptian through displacement; (4) there are no other pipeline or storage alternatives of which the Company is aware; (5) maintaining the Egyptian storage service contract would result in an expenditure for storage capacity that could no longer be utilized as a part of firm city gate deliveries; and (6) TETCO's owner, Duke Energy, was known to call transmission interruptions on a non-discriminatory basis with no exceptions or credit given for backhaul situations.

Q. Please explain why the decision was made to cancel the Egyptian storage agreement.

A. The Company did not want to put its Harrisburg operating area customers at risk of having the storage capacity from the Egyptian storage facility, representing 30% of the MDQ, interrupted during the coldest and worst winter weather with the potential of not having the gas or being forced to pay extremely high penalty prices if gas was delivered even through an interruption. These results would be unacceptable because of the Company's obligation to make sure gas is available to firm customers on a firm delivery basis.

Q. How was the termination of the Egyptian storage contract accomplished?

A. A termination notice was sent on August 26, 2004, advising Egyptian that the Company was terminating the storage agreement effective May 1, 2005. A true and correct copy of the termination notice is attached hereto and labeled Exhibit MM-R-5.

Q. Why was the termination notice given so far in advance of the actual termination date?

A. Section 4.1 of the Egyptian agreement specified that the storage agreement could only be terminated effective April 30 of any given year and that notice must be given not less than six months prior to that date. Notice was given more than six months' in advance and upon the Company's decision to proceed with the termination of the storage agreement. This was shortly after the Company learned that Consumers Gas Company had terminated its exchange agreement with AEM.

Q. After Consumers terminated its exchange agreement with AEM, did the Company sign an interruptible transportation service agreement with TETCO?

A. No. The TETCO IT service agreement was already in place and had been so for more than ten years.

Q. Did the Egyptian storage contract specify when the Company could withdraw its storage gas?

A. Yes, the Company was expected to withdraw, subject to storage field operational considerations and the terms and conditions of the contract, storage gas between November 1 and March 31. Also, as storage field operations permitted, the Company could withdraw storage gas between May 20 and October 31; however, this time period was typically used for injection.

Q. What volumes were the Company permitted or required to store in Egyptian?

A. At the time of termination, the Company's maximum storage volume for working gas was 400,000 dekatherms. In addition, the Company was required to maintain a balance of 100,000 dekatherms of cushion gas. Accordingly, the Company could have up to 500,000 dekatherms of gas in the storage field at any given time.

Q. What is the difference between working gas and cushion gas?

A. Cushion gas is that level of gas that the storage field operator (in this case Egyptian) has determined to be necessary to maintain the operational integrity of the field and it cannot be withdrawn during the normal course of a storage contract. Working gas is the gas that the Company was permitted to withdraw from the field at any time, subject to contractual and operational limitations. Once the contract with Egyptian ended, the Company would be permitted to withdraw its residual storage balance which consisted of a quantity of gas equivalent to the Company's contractual cushion gas level plus any remaining balance of the Company's working gas. However, as long as there was working gas in the storage field, the cushion gas could not be withdrawn.

Q. When the Company sent the termination notice to Egyptian, was the Company injecting storage gas into the field?

A. Yes. The storage contract was not terminating until the following spring, so the Company elected, since it was paying for the service through April, 2005, to proceed according to its supply plan and utilize the storage for the 2004-05 heating season.

Q. Was the Company able to withdraw its storage gas from the Egyptian storage field between November 1, 2004 and March 31, 2005?

A. Not all of it. The weather during this time period was approximately 14% warmer than normal and as a result, the Company did not withdraw all of the gas from Egyptian for system supply as planned under its planning schedule for the Harrisburg operating area.

Q. How did you conclude that the weather was 14% warmer than normal during this time period?

A. This conclusion is based upon information published by the National Oceanic and Atmospheric Administration (NOAA) for the typically three coldest months of the winter season – December, January and February. The data published by NOAA for the region covering Harrisburg, Illinois is as follows:

DECEMBER 2004	Average Monthly Temp.	Departure from Normal	Records
Paducah, KY	35.8°	-1.1°	
Evansville, IN	33.8°	-1.8°	
Carbondale, IL	34.2°	-1.0°	
Poplar Bluff, MO	37.3°	-0.3°	

JANUARY 2005	Average Monthly Temp.	Departure from Normal	Records
Paducah, KY	41.0°	+7.1°	6th Warmest
Evansville, IN	38.7°	+7.2°	
Carbondale, IL	38.6°	+8.0°	
Poplar Bluff, MO	40.1°	+7.4°	

FEBRUARY 2005	Average Monthly Temp.	Departure from Normal	Records
Paducah, KY	43.7°	+4.8°	
Evansville, IN	40.8°	+4.5°	
Carbondale, IL	42.2°	+7.7°	
Poplar Bluff, MO	43.7°	+7.4°	

Based upon the foregoing data, the 3-month average departure from normal for Carbondale was almost 14%. The Carbondale, IL averages were used for this analysis because Harrisburg is approximately 37 miles from Carbondale.

As of the end of the heating season, the Company had a balance of 155,308 dekatherms of gas remaining in the Egyptian storage field. Of this balance, 100,000 dekatherms was cushion gas and the remainder was working gas. The remaining balance of working gas represents approximately 15% of the initial working gas balance and virtually mirrors the impact of the 14% warmer than normal weather for that season upon the Company's storage withdrawals.

Q. Can you provide an analysis comparing the Company's projected storage plans (both initial and revised) with the Company's actual Egyptian storage for 2004-05?

A. Yes. The table below shows the calculations of storage volumes (both cushion and working gas) for Egyptian under the Company's initial plan, its revised plan and actual results for the 2004-05 heating season (all volumes are in dekatherms):

	Initial Plan	Revised Plan	Actual
Cushion Requirement	100,000	100,000	100,000
Injections	358,000	358,000	357,040
Less Withdrawals	347,300	358,000	301,732
Working Gas Balance	9,740	0	55,308
Final Storage Gas Balance (Working and Cushion)	109,740	100,000	155,308

At the time that the initial and revised storage plans were prepared, the total actual injection volume of 357,040 was not known. The total cushion requirement of 100,000 had been injected in the past and was a carry forward book balance.

It should be pointed out that the 358,000 injection balance was an estimate the Company used in designing its withdrawal plan in September 2004 and was revised in mid-October 2004. This estimate turned out to be slightly higher than the actual pre-season storage balance of 347,040 which became known in mid-November 2004.

Q. What was the volume of natural gas stored in Egyptian that the Company sold to Egyptian Gas Storage?

A. 155,308 dekatherms. This was the entire remaining volume of natural gas in Egyptian owned by the Company, both working and cushion gas. The documentation of the sale is attached hereto collectively as Exhibit MM-R-6.

Q. Why didn't the Company use the 45-day extension period in the storage contract for purposes of withdrawing its remaining storage gas from Egyptian?

A. The 45-day extension period (Article 4.2 of the Egyptian storage agreement) would have been the period of May 1, 2005 to June 15, 2005 and would therefore have fallen outside of the contractually permitted withdrawal periods – the winter period (defined by the contract as November 1 through March 31) and the summer period (defined by the contract

as May 20 through October 31). However, article 1.2 of the agreement states that the Company could withdraw volumes during the summer period if "Seller's operations permit". Egyptian would not permit withdrawals until the next winter period began. Exhibit MM-R-7 attached hereto is a copy of an internal Company memo dated March 28, 2005 that discusses the fact that the Egyptian storage field would be down during April 2005 for maintenance. The Company was told by Egyptian that it could not withdraw any storage gas during the injection season which eliminated the opportunity to withdraw the Company's storage balance during the 45 day extension period.

Q. What were the options left to the Company?

A. The options that were available to the Company under the field's operating conditions at the time were: (1) continue the contract, pay the $15,000 per month storage charge and then attempt to withdraw the residual balance during the next withdrawal period; or (2) sell the residual balance and avoid the monthly storage service fee. The Company chose the latter.

Q. Why was this course of action the proper decision?

A. When all of the pertinent facts are considered, selling the residual balance in place was the proper decision. The Company sold its residual storage gas to Egyptian for a total consideration of $970,675, or $6.25 per dekatherm ($970,675/155,308 dekatherms). The market price index (InsideFERC, TETCO ETX) at that time was about $6.55 per dekatherm, for a potential sales amount of $1,017,332 to another taker. The Staff has recommended an adjustment in the amount of $46,657.38 relating to the sale of the residual storage gas, which is the difference between $1,017,332 and $970,675. However, if the Company had sold the gas to a party other than Egyptian, it would have also incurred

contractual charges assessed by Egyptian consisting of 1) a withdrawal fee of $0.05 per dekatherm, or $7,765 (155,308 X $0.05), plus 2) a 2% retention, or $20,344 (155,308 X .02 = 3,106 dekatherms X $6.55 = $20,344). Therefore, the net proceeds would have been $989,223, assuming (1) the storage gas could have been withdrawn and (2) the Company had a purchaser who was willing to pay full index price for the gas. The additional hypothetical sales proceeds would actually have been $18,548. Moreover, the Company would have had to deliver the gas elsewhere on the TETCO transmission system and, depending on delivery time, transmission loading and pipeline operation, would have incurred pipeline transportation charges which might have ranged from no charge to $4.256 per dekatherm. This could have quickly dissolved the $18,548 in additional hypothetical proceeds.

Q. Are there any additional facts that should be considered in your above analysis?

A. Yes. There is one additional factor. The Company was able to convince Egyptian to waive the monthly contractual demand charges of $15,000 for the month of April. This additional savings substantially offsets the $18,548 in hypothetical sales proceeds. Here is a summary of the value to ratepayers of the Company's decision to sell its residual storage gas in place:

Actual Proceeds	$970,675
Avoided Withdrawal Charges	7,765
Avoided Retention	20,344
Waived Demand Charge	15,000
Total Sales Consideration	$1,013,784

Even without considering the value of the additional TETCO transmission charges that were avoided by selling in place, this is equivalent to $6.528 per dkth which is very close to the index price at the time of $6.55 per dkth. Accordingly, the Company does not believe that the Staff's recommended adjustment in the amount of $46,657.38 relating to the sale of the Company's residual storage gas in Egyptian is justified.

Q. You previously mentioned the Company had two options relating to the residual gas in storage, one of which was to wait until the next withdrawal season. What would have been the economic impact of this decision if the Company had made such an election?

A. The Company would have incurred additional monthly storage fees if the contract continued until there was no residual balance. Assuming that the residual balance could have been withdrawn in November 2005, the Company would have incurred additional costs of $120,000 ($15,000 demand charge per month for April through November) which is an additional $0.77 per dekatherm.

Q. Previously, you mentioned two additional storage fields that were part of the capacity resources for the Harrisburg operating area. Would you please explain how those storage fields were utilized?

A. Yes, the Wiseman and Ellis storage fields are located behind the Harrisburg operating area city gate and are therefore firm capacity assets for the Harrisburg operating area. Both of these storage fields are owned by Gallagher Drilling Co. In combination, these two fields were contractually obligated to deliver 5,000 dekatherms per day to the Harrisburg operating area. In late 2005, the Company began discussions with Gallagher Drilling regarding the potential to enhance the Wiseman field to increase its deliverability, so

that it would be operating at the same efficiency level at which the Ellis field was operating. Both the Company and Gallagher had the expectation that the Wiseman field could be enhanced successfully. As a result, in the 2004-05 timeframe, the Company anticipated that the firm storage deliverability behind the Harrisburg city gate would be maintained at 5,000 dekatherms per day from the combination of the Wiseman and Ellis fields. It was not until early 2007 that the Company and Gallagher Drilling came to the conclusion that Wiseman could not be enhanced and needed to be depleted and the project closed. The Company is still receiving 3,000 dekatherms per day from the Ellis field.

Q. Could the Egyptian storage capacity been a substitute for the Wiseman storage capacity if the 2007 facts were known in 2005?

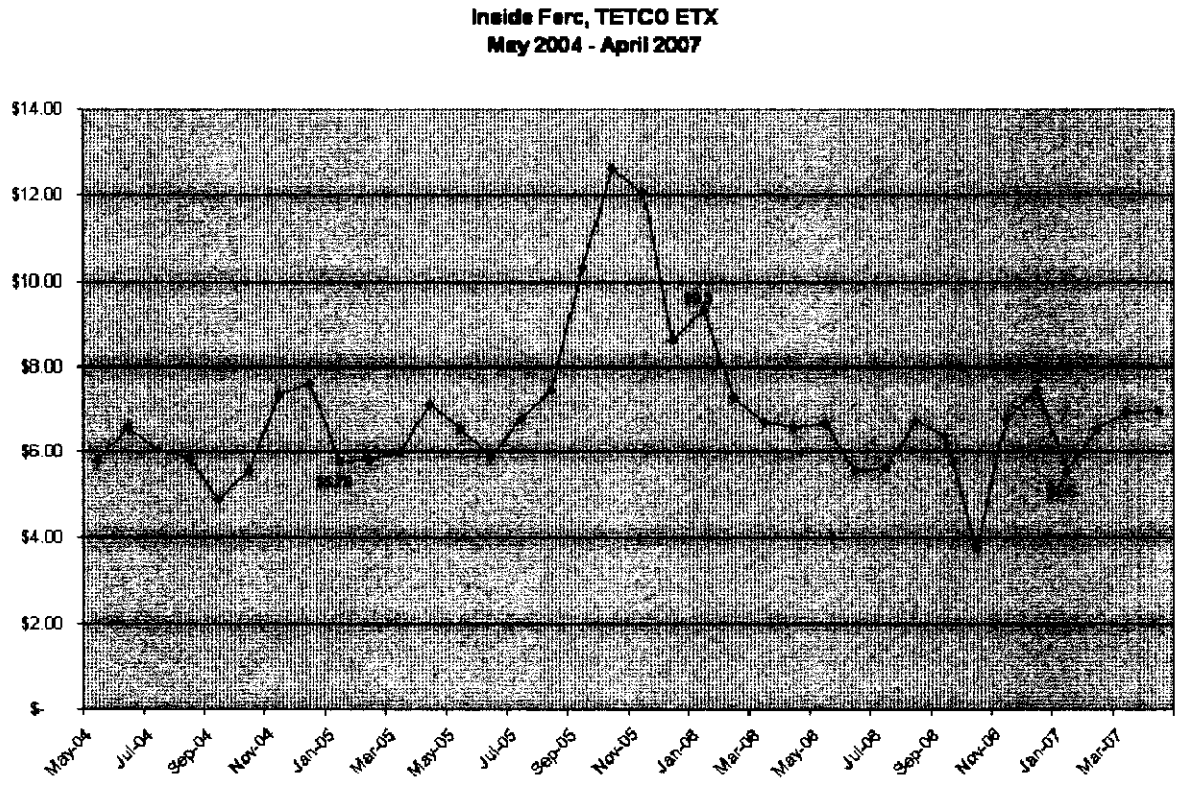
A. Although these facts were not known in 2005, the answer would be no because the Egyptian storage without the exchange agreement between Consumers Gas and AEM could only be considered an interruptible storage asset. On the other hand, the location of the Wiseman field made that capacity a firm storage asset.

Q. Can storage assets create a natural hedge?

A. At one time, it seemed reasonable that storage could create a natural hedge. However, looking at the volatile gas markets of the last several years, a hedge is very difficult to find.

An examination of the InsideFERC price for ETX from May 2004 through April 2007, the most recent three years, reveals a picture completely different than might be intuitively expected. For the period May 2004 through April 2005, the first of the month price for January was less than seven of the other 2004-2005 months (July, August, November,

December, February, March, and April). This grouping included three of the seven injection period months. For the period May 2005 through April 2006, the period of time that encompasses Hurricanes Katrina and Rita, the first of the month price for January was less than three of the other months (September, October and November). This 2005-2006 grouping includes two of the seven injection period months. For the period May 2006 through April 2007, the first of the month price for January was less than eight of the other months (May, August, September, November, December, February, March, and April) and was the same price as June. This 2006-2007 grouping includes four of the seven injection period months. The foregoing is illustrated in the following graph:



Each one of the injection period months was higher than or equal to the January price during this three year period. Because there is no solid pricing pattern for injection peri-

ods versus withdrawal periods, any natural hedge would be impossible to create with seasonal injections and withdrawals. Therefore, the Company would not be comfortable "playing the market" trying to establish a storage hedge.

Q. Previously in this testimony you stated that the Company gave up firm capacity that it held on the TETCO pipeline. Would you please explain why?

A. More than six years ago the Company gave up its firm capacity on the TETCO pipeline and utilized the Consumers Gas Company/AEM exchange agreement to facilitate gas supply delivery to the Harrisburg operating area. By utilizing displacement, the Company was able to avoid substantial costs to ratepayers in the form of unneeded firm capacity on TETCO. Under the exchange agreement arrangement, the Company only paid a demand charge of $0.08 per dekatherm to AEM plus $0.03 per dekatherm to Consumers to transport the gas from Egyptian to Consumers' city gate for a total of $0.11 per dekatherm during the term of the exchange agreement. This is significantly less than paying a pipeline demand charge of $4.256 per dekatherm to TETCO. The Company saw no need to continue to hold idle, expensive firm capacity on the pipeline when it had a more cost-effective alternative to effectuate firm supply deliveries.

Q. Why did the Company not retain its firm capacity as a back-up to delivery through displacement?

A. At the time, the Company had no reasonable basis to believe that the displacement arrangement would not continue into the future and retention of that capacity would have been a duplicative gas supply expense. By releasing the capacity, the Company was able to avoid substantial costs to the Company's retail customers.

Q. Can you quantify the avoided costs to the retail customers in the Harrisburg operating area?

A. Yes. TETCO Contract #830019, which provided for a maximum daily quantity of 11,457 dekatherms, was terminated effective July 31, 1996. For the period of August 1996 through June 2004, the Company has saved/avoided approximately $4,600,000 in additional pipeline charges based upon maximum pipeline tariff rates.

TETCO Contract #800275, which provided for a maximum daily quantity of 1,450 dekatherms, was terminated on October 31, 2001. For the period of November 2001 through June 2004, the Company saved/avoided approximately $200,000 in additional pipeline charges based upon maximum pipeline tariff rates.

TETCO Contract #830018, which provided for a maximum daily quantity of 393 dekatherms, was terminated effective October 31, 2001. For the period of November 2001 through June 2004, the Company saved/avoided approximately $54,000 in additional pipeline charges based upon maximum pipeline tariff rates.

In the aggregate, the Company saved/avoided approximately $4,900,000 in additional pipeline charges on account of the termination of the TETCO firm capacity agreements as shown below:

800275 - Terminated 10/31/2001
MDQ 1,450

2001	1450 x $4.246 x 2 months	$12,342
2002	1450 x $4.246 x 12 months	$74,054
2003	1450 x $4.246 x 12 months	$74,054
2004	1450 x $4.246 x 6 months	$37,027
		$197,478

830018 - Terminated 10/31/2001
MDQ 393

2001	393 x $4.256 x 2 months	$3,345
2002	393 x $4.256 x 12 months	$20,071
2003	393 x $4.256 x 12 months	$20,071
2004	393 x $4.256 x 6 months	$10,035
		$53,523

830019 - Terminated 7/31/96
MDQ 11,457

1996	11,457 x $4.256 x 5 months	$243,804
1997	11,457 x $4.256 x 12 months	$585,131
1998	11,457 x $4.256 x 12 months	$585,131
1999	11,457 x $4.256 x 12 months	$585,131
2000	11,457 x $4.256 x 12 months	$585,131
2001	11,457 x $4.256 x 12 months	$585,131
2002	11,457 x $4.256 x 12 months	$585,131
2003	11,457 x $4.256 x 12 months	$585,131
2004	11,457 x $4.256 x 6 months	$292,565
		$4,632,294

Total **$4,883,295**

Q. After Consumers Gas Company canceled the exchange agreement resulting in the inability to utilize Egyptian storage as a firm gas resource, how did the Company ensure firm delivery of its purchased gas to its Harrisburg operating area?

A. Through a combination of the Company's interruptible transportation service on TETCO and bundled firm service, all of which is more fully discussed in the next section of my testimony.

Q. Could the Company have continued to hold this firm capacity on TETCO and allow other parties to use that capacity in order to transport gas over the TETCO system?

A. Not without doing seasonal capacity releases pursuant to the FERC's capacity release rules. The Company's experience has been that revenue derived from capacity releases for small systems such as Harrisburg has historically been insignificant. The Company could not otherwise provide transportation for third parties utilizing its capacity because

the FERC's rules prevent that from occurring, specifically the "shipper must hold title" rule that is explained later in this testimony.

IV. THE GAS SUPPLY PLANNING PROCESS

Q. Does the Company have an established process in place to analyze and evaluate the supply needs for each of its operating systems?

A. Yes. This process involves analyzing, evaluating, and forecasting both commodity and deliverability requirements. The commodity requirement is how much does the system need and the deliverability requirement is how to get the commodity to the system. The beginning point for both components is design day analysis.

Q. What is design day analysis?

A. Design day analysis is the methodology the Company (as well as most gas distribution companies) uses for projecting system load requirements to meet the natural gas consumption needs of the Company's firm sales customers (residential, public authority and small commercial). The Company's design day computation uses a minimum of two years of historical volumetric data for the months of December, January, and February. After non-firm deliveries are deducted from the total supply into the system, a type of regression analysis is used to determine the daily firm load for a given heating degree day (HDD). Using at least thirty years of temperature data, the design day HDD is determined by selecting the peak HDD for each winter season, arranging into groups of ten years, observing the highest HDD in each ten-year period, and calculating a weighted average peak HDD based on the frequency of occurrence in each of the ten-year periods. Then, the design day requirement is calculated from the regression formula for the computed peak HDD.

Q. How is the commodity requirement evaluated?

A. Once consumption requirements are forecasted, the quantity required for the actual gas commodity is determined for baseload and peak day. Baseload is the base volume of natural gas required to meet firm sales customer consumption requirements on a day-in, day-out basis. Peak day is the volume of natural gas above baseload that would be required to meet firm sales customer consumption requirements on the coldest forecasted day of a given heating season. Because no one can predict the weather with any absolute certainty, baseload and peak day volumes are established with a reasonable cushion. Once the commodity requirement for a system has been determined, that will be utilized for the requests for proposal for gas supply.

Q. How is the deliverability requirement evaluated?

A. In evaluating deliverability, the primary concern for the Company is to ensure that natural gas is available to its firm sales customers when they need it. Inasmuch as the Company's system supply comes through the interstate pipeline systems, the Company, either directly or through arrangements with other parties, must have firm capacity for its system supply or receive firm city gate delivery.

Q. What is the reason for holding a contract for interruptible transportation service?

A. Mainly for pricing flexibility. There will be times when firm capacity for a portion of the Company's system supply is not needed, particularly in warmer weather. At such times, it may be more cost-effective for the Company's customers if volumes are nominated for delivery under the Company's interruptible transportation service agreements. There are typically no charges for interruptible service until the service is actually used, unlike firm

capacity where recurring monthly demand charges are paid to the pipeline. Accordingly, there is no cost for simply maintaining interruptible transportation service arrangements.

Q. Previously in this testimony you discussed the Company's Harrisburg operating system and its proximity to interstate pipelines. Does that discussion bear upon the Company's gas supply planning process?

A. Yes. The availability or unavailability of firm capacity on the TETCO pipeline requires the Company to evaluate capacity alternatives. However, as previously discussed, there are no other pipelines that are geographically proximate to the Company's Harrisburg operating area. Therefore, the Company is largely dependent upon third parties' capacity until such time as any firm capacity becomes available on TETCO and the Company can obtain the firm capacity directly.

Q. Can the Company contract with another party who holds firm capacity on TETCO to use that capacity?

A. Not directly for the capacity only. As an interstate pipeline, TETCO is regulated by the FERC. FERC has a rule known as the "shipper must have title" rule which requires a shipper to have a capacity contract with the pipeline and to hold title to the gas that is being transported using that shipper's capacity on the pipeline. In other words, this rule will not allow the Company to directly use another party's capacity on TETCO to facilitate the delivery of the Company's own gas commodity to the Harrisburg city gate.

Q. If the Company cannot use another party's capacity, then how can it ensure firm delivery of system supply to the Harrisburg city gate?

A. By bundling commodity and delivery. In other words, purchase the commodity from another party who can guaranty firm delivery to the Harrisburg city gate. The selling/delivering party will have its own firm capacity on TETCO.

Q. Has the Company contacted TETCO concerning the availability of firm capacity?

A. Yes. The Company routinely contacts TETCO about twice per year to see if and when any firm capacity could possibly become available. As of yet, no firm capacity has become available and TETCO has no current plans of which the Company is aware to increase the capacity on the segment of its system that serves Harrisburg. The Company will continue to monitor firm capacity availability on TETCO.

Q. Based on the Company's gas supply planning process, what were the results for the Harrisburg operating area for November 2005 through October 2006?

A. The baseload capacity requirement was 4700 dekatherms per day and the peak capacity requirement for the winter period of November 2005 through March 2006 was 7600 dekatherms per day.

Q. With these results, was there an impact on how the RFP for 2005-06 was structured?

A. Yes, the Company fashioned its RFP to include a peaking service so that the costs for the resulting supply contract would more closely track the gas supply needs of the Harrisburg operating area. This meant that the Company asked the wholesale market for a supply-shaping service. The peaking service had been successfully used by the Company in the previous year and the Company believed that this would be a prudent practice to continue for the 2005-06 season. Specifically, the Company used a peaking service for the 2004-05 season and paid an aggregated price for baseload and peaking service for all 12

months. The 2005-06 season had separate pricing for baseload and peaking so that the peaking could be more closely sculpted for system supply needs.

V. THE GAS SUPPLY PROCUREMENT PROCESS

Q. Can you describe the Company's gas supply procurement process?

A. Yes. As I previously described, the Company develops a seasonal gas supply plan based on normal weather. The Company incorporates those normalized requirements into a Request for Proposal (RFP). The Company employs a competitive bidding process. A list of qualified prospective bidders is maintained by the Company and they are sent a RFP package soliciting their proposal for the Company's supply needs for a one year period. The RFP outlines the process to submit a proposal, including the deadline, and specifies that the Company will not have any meetings with any bidder until the RFP has been awarded. Once proposals are received, they are date stamped and held unopened until the deadline passes, and any proposals received after the deadline are returned to the supplier unopened. All proposals remain confidential within the Company and are not shared with anyone outside of AEC (other than the ICC Staff and our consultants). A preliminary review of all proposals received is performed by me and a Gas Supply Specialist. The Gas Supply Specialist then evaluates all proposals timely received and presents the analysis to me. I then review the analysis and confirm the winning bidder. We contact the division's Vice President of Rates and Regulatory Affairs for approval. After approval is received, a contract is executed with the winning bidder.

Q. Who is considered to be a "qualified prospective bidder"?

A. The Company's maintains a list of vendors with which the Company has already done business throughout its multi-State territory and vendors which have previously ex-

pressed an interest in doing business with the Company. All vendors must be experienced and financially sound.

Q. Does the Commission have any specific requirements regarding the RFP process?

A. Yes. Section 310.70 of Title 83 of the Illinois Administrative Code sets forth the Commission's rules for competitive bidding that apply when an affiliate of the utility is included in the RFP process. The Company's RFP process is set up to comply with the requirements of the Commission's competitive bidding rules. In fact, the Company worked with Staff to create the Company's RFP guidelines to make sure that the Company would meet the requirements of Section 310.60(e) of Title 83 of the Illinois Administrative Code. The Company's RFP guidelines were finalized in June 2003, and the Company has made them an addendum to its RFP procedures.

Q. What comprises the RFP package?

A. The RFP defines the commodity and services requested. It specifies (a) the contract term for pricing purposes, (b) the commodity and/or transportation service requirements, (c) the points of receipt and delivery, (d) the point where title to purchased gas transfers, (d) the party or parties responsible for performing nominations and (e) required warranties. The RFP also specifies that the contract to be entered into between the Company and the supplier will include all of the foregoing information as well as its billing and payment requirements and dispute resolution provisions. Because most gas supply contracts employ the standard contract form promulgated by the North American Energy Standards Board (NAESB), the RFP will also include the Company's standard exceptions to the NAESB form. Vendors also have the ability to specify any of their own exceptions or modifications to the NAESB form agreement.

Q. Does the Company publish any public notice regarding a supply RFP?

A. Yes. Starting two weeks prior to the deadline for submission of proposals to the Company, the Company places, for two consecutive weeks, a public notice requesting bid proposals in the official state newspaper designated by the Illinois Department of Central Management Services and a local newspaper of general circulation in the Company's Illinois service area. The local newspaper used by the Company is the Daily Register in Harrisburg, Illinois.

Q. What is the timeline for the delivery, receipt and analysis of RFPs?

A. The RFP package is put together and finalized at least 5 weeks in advance of the expiration of the existing contract that is the subject of the RFP. The RFP is then sent to prospective suppliers. The response deadline is a minimum of 7 days after their receipt of the RFP. The RFP further specifies that that the Company's analysis of proposals and a final decision will be accomplished not later than 7 days after the deadline for the proposals.

Q. What happens after the winning proposal has been determined?

A. The Company will endeavor to negotiate and execute a final contract with the winning supplier within 2 weeks after the winning proposal has been announced.

Q. Does the Company make any subsequent filing with the Commission?

A. Yes. The Company files with the Commission a statement of the transaction, including a copy of the contract and an un-expunged proposal tabulation. Copies of the filing are also provided to the Commission's Accounting Division and Energy Division engineering group.

Q. How many RFPs were sent to prospective suppliers for the 2005/2006 RFP?

A. Eight.

Q. How many suppliers responded?

A. One. That was AEM.

Q. How many RFPs were sent to prospective suppliers for the preceding year?

A. We sent RFPs to 12 prospective suppliers for the 2004/2005 RFP.

Q. How many suppliers responded for the 2004/2005 RFP?

A. One. That was AEM.

Q. How many RFPs were sent out for the 2003/2004 season?

A. We sent RFPs to 16 prospective suppliers.

Q. How many bidders responded?

A. Two, one of which was AEM. AEM also had the best proposal for that year.

Q. Why did the number of bidders decrease from 16 to 12 to 8 over the 3-year period?

A. I attribute this to the fact that the Company did not receive responses back from several bidders, who were initially on the bid list, stating that they desired to remain on the list. The RFP instructs a vendor to contact the Company, even if they do not plan on bidding, and express their desire to remain on the list.

Q. With so few proposals for the Harrisburg RFP, how can this process be considered competitive?

A. The rules under which the RFP process is conducted assure the Company, its customers and the Commission that the resulting pricing is market driven and thus competitive. The key to this competitive pricing result is that each respondent to the RFP has to assume that there are competing proposals and, as a result will respond with the best proposal possible. In this case, AEM did not know whether there were several competing bids or

none, which required them to submit their best possible pricing proposal. None of the suppliers that received the RFP package know whether and which competitors responded with proposals.

Q. Why did the AEM proposal include a fifty-five cent per dekatherm adder?

A. Because of the competitive process as described above, we must assume that it was market established. Although I do not profess to have any first-hand knowledge of how AEM evaluates and values the services it provides, I believe that this reflected a margin for perceived risks and possibly recognition of the premium supply-shaping services I mentioned previously.

Q. Please explain what the adder is.

A. The adder is associated with the supply. Since the Company is receiving a city-gate delivered service, there are two price components. The first is for pipeline capacity and the second is for the actual supply. These pricing components are mutually exclusive and would exist no matter what vendor provided the city-gate delivered service.

Q. Why have there been so few proposals for the Harrisburg operating area supply?

A. The Company can only speculate on why other suppliers have not submitted proposals for the Harrisburg RFP. Since TETCO is fully subscribed, the suppliers with available supply and firm capacity may be limited. The Company does not carry excess capacity on those pipelines for which it has been able to subscribe for firm capacity and assumes that, likewise, other parties also only subscribe for what they need. If so, then the pool of suppliers with available capacity may be limited.

Q. Do you believe that the Company's release of its firm capacity on TETCO six years previously decreased the number of prospecitive bidders for the 2005-06 supply?

A. No. If that were the case, it would have entailed that the Company, at the time of the capacity release, be able to forecast any such effect. As I stated previously, the Company had no reason not to believe at the time that the exchange service would continue to be available as a more cost-effective alternative to direct firm pipeline capacity.

Q. Do you believe that the structure of the 2005-06 RFP contributed to a reduced number of bidders?

A. No. Although the RFP does state that there are two services being bid (without specifying any bundled service requirement) and defines the proposed terms of each service, it may not have been entirely clear that the Company would entertain proposals that separate the two required services. A true and correct copy of the RFP is attached hereto as Exhibit MM-R-8. The Company had received bundled bids for several years and it may very well be that bidders placed more value on the entire business as opposed to only a portion. However, there is nothing to demonstrate that non-bundled bids would have affirmatively resulted in lower costs to ratepayers. In fact, to assume otherwise presumes that the natural gas market contains only companies that have expertise or place value on a niche piece of business. This presumption would be erroneous, however, because the natural gas market is abundant with marketers that have diverse portfolios as well as companies that pride themselves on being able to offer a wide range of services. Such an assumption also presumes that each bidder would value each aspect of the RFP differently. While it may be possible for several vendors to bid lower on one of several supply components, such a generality cannot support the conclusion that the methodology employed by the Company was imprudent.

Q. Prior to this proceeding, have any concerns been expressed that the Company was only receiving one bid for the Harrisburg area?

A. No. The Company has always followed a competitive bid process. The Company has also worked with Staff to ensure that the Company follows Commission guidelines so that if an affiliate does submit the winning bid, the Company has gone through all appropriate channels to award the business to an affiliate.

Q. Does a utility such as the Company have a greater incentive to negotiate another result with an unaffiliated marketer?

A. Regarless of whether the successful bidder is an affiliate or an unaffiliated third party, there is really no negotiation process and the Company awards all of its Illinois business through the competitive bid process. Otherwise, the Company would be faced with two compliance standards when an affiliate makes a bid. First, the Company must follow a competitive bidding process, which it did. Second, if an affiliate was the winning bidder, then the Company would have to try and negotiate further with its affiliate for a better deal. Such a system would be unworkable and is not required by the Commission's rules.

Q. Why is such a system unworkable?

A. Because it imposes additional requirements upon the Company to (1) speculate what another bidder or bidders might have submitted in the RFP process when the affiliate is the only bidder and (2) to try to negotiate with the affiliate a better deal based upon such speculation. If the affiliate was unwilling to re-negotiate its bid, then the Company would essentially be required to begin the whole RFP process all over again.

The Company's understanding of the Commission's affiliate and competitive bidding rules is that they were intended to provide a level of protection to ratepayers to ensure

that utility affiliates do not get a better deal than another party would have and that the affiliate's transaction is at arms length. As I discussed in more detail earlier in my testimony, the Company complies with the Commission's rules. These rules provide that contracts made by a public utility with a person or corporation whose bid is the most favorable to the public utility, as ascertained by competitive bidding under the rules for competitive bidding, need not be filed with or approved by the Commission. Nevertheless, as stated earlier in my testimony, the Company does actually file the contracts with the Commission. If the Commission deems it advisable to preclude or more severely limit utility affiliates from bidding on utility gas supply and other services than as already required by the Commission's rules, then the Commission should clarify this through a formal rulemaking process and not on an *ad hoc* basis in a gas cost proceeding by requiring the Company to go above and beyond the rules.

Q. Does Staff take issue with the Company's bid analysis process?

A. Yes. Staff's critiques include failure to compare bids to the prior year's contract, making agreements between affiliates, lack of base load gas pricing options and that the index pricing selected by the Company resulted in higher costs to ratepayers.

Q. Did the Company compare bids for the 2005-06 season to the prior year's contract?

A. The Company's analyses only cover the bids received for that particular RFP, not multiple periods. Due to the volatility in the natural gas market, there are no assurances that the pricing for a previous year will be a valid benchmark for the subsequent year's pricing.

Q. Did any agreement between Company affiliates affect the bid analysis process?

A. No. Although the Company's affiliate, Atmos Energy Services, LLC (AES), conducted the bid analysis, it did so as part of gas supply services provided to the Company. In Docket 04-0405, the Commission approved the sourcing of the Company's gas supply function to AES.

Q. Did the Company evaluate the AEM bid to determine whether it contained any options for base load pricing?

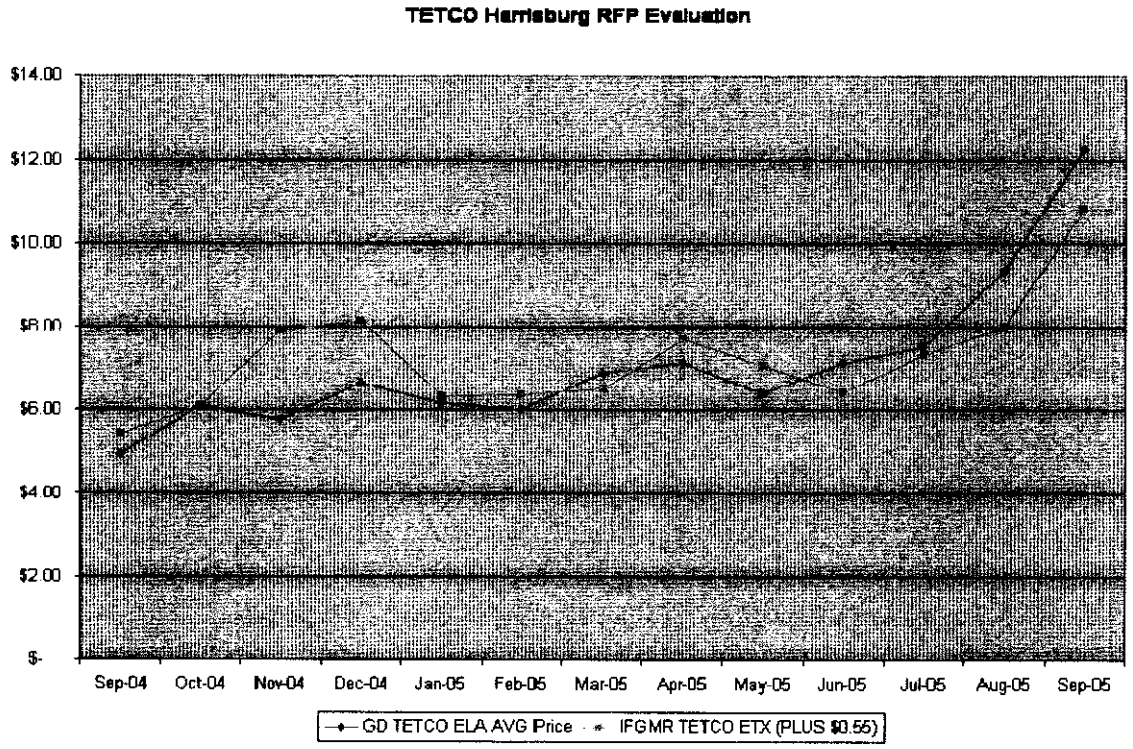
A. Yes, AEM's response to the RFP, which is submitted in this proceeding as Staff Schedule 2.07, clearly lists the two options under the section labeled *Monthly Base Load and Swing Quantity up to 4,700 dth/day*. Under this section there are three separate sentences. The first outlines the pricing for the capacity. The second and third are the options for base load supply. The Company's bid analysis, which is submitted in this proceeding as Staff Schedule 2.08, shows that the Company was given two options for base load pricing and that the Company selected the Inside FERC, TETCO ETX index plus 55 cents.

AEM's bid is probably not quite as clear as it probably could have been regarding the two price options. When it received AEM's bid, the Company contacted AEM for clarification and AEM confirmed that it was two options for base load pricing. There was no negotiation of the bid, just clarification.

Q. Should the Company have selected the Gas Daily, Daily Midpoint, TETCO ELA flat rate baseload pricing option?

A. No. The Gas Daily index, as appropriately named, is published daily. With the extreme volatility that the natural gas market continues to experience, the daily market is the most volatile. In order to determine whether the base load pricing option selected was prudent, the Company analyzed the historical prices for IFGMR, TETCO ETX index plus $0.55

versus Gas Daily, Daily Midpoint, TETCO ELA flat for the period September 2004 through September 2005 (September 2005 data contained data through September 28, 2005). While eight months out of thirteen months showed the Gas Daily index as being less, the most recent four months and five months out of the most recent seven months showed the IF index as being less. The Company chose to rely on the most recent four months more heavily, especially August and September of 2005. Both of those months were showing over $1.30 difference in favor of the IF index. The foregoing is demonstrated in the following chart:



The market was in disarray due to Hurricanes Katrina and Rita and no one knew where the market was headed. The Company believes that it made the best decision considering the circumstances at the time.

Q. Is there any adjustment recommended in this proceeding relating to the Company's analysis of the AEM bid?

A. Yes. Staff proposes an adjustment in the amount of $48,879.

Q. Is the proposed adjustment reasonable?

A. No. The facts demonstrate that the Company's was prudent in performing its analysis

Q. Will the Company implement any modifications for subsequent RFP's for the Harrisburg operating area?

A. Yes, inasmuch as concerns have been expressed about the Company's methodology. In an effort to allay any such concerns, the Company will make it very clear in its RFP package that it welcomes unbundled service proposals. Also, the Company will schedule the release of the Harrisburg RFP earlier in the requesting year, such as the July/August timeframe. In addition, the Company will try and increase the number of vendors on its approved vendor list.

Q. Why is the Company proposing to take these steps in future RFP processes?

A. The Company would much prefer to have multiple responses to its RFPs. If these steps have a chance of encouraging multiple responses, we will pursue them. However, when all is said and done, the Company has no control over the respondents to the RFP.

Q. You have mentioned supply-shaping twice previously in your testimony. Would you please explain how the firm supply was structured previously?

A. Yes. For the 2004-05 season, the Company contracted for baseload supply of 4,700 dth/d beginning November 1, 2004. The Company also had a ten-day peaking service of 3,600 dth/d for the winter months of November through March. During that period, the Company paid an aggregated price of $33,670 per month for both services. I misspoke

on lines 17-18 on page 7 of my direct testimony previously filed in this proceeding when I mentioned that the Company had "adjusted the amount of first of the month firm deliveries downward". The baseload quantities of 4,700 dth/d from the November 2004 contract remained constant in the November 2005 contract.

Q. How was the firm supply structured for the 2005/2006 season?

A. For the 2005/2006 season, the Company believed that it did not need the 8,300 dekatherms year round so there was no need to pay for it. Instead, the Company sculpted supply to its needs. The Company believed that it would need 4,700 dekatherms year round, but also the option of an additional 2,900 dekatherms during the winter months. This option allowed the Company to avoid having unnecessary capacity during the warmer months.

Q. Why was the peaking service needed?

A. Because it allowed the Company to avoid the necessity of subscribing to excessive levels of baseload volumes for long periods of time. The peaking service volumes will fluctuate based on the Company's design day requirements and the Company determined that there was no need to contract for the same amount of baseload quantities year round. For the 2005/2006 season, the peaking service was needed for two reasons: (1) meet design day requirements and (2) help to replace the exchange agreement linked to Egyptian storage. The Company is obligated to meet firm requirements of its firm customers. The peaking service provides the amount of firm capacity that would be needed to meet our firm requirements under peak conditions in order to insure sufficient firm supply. For the November 2005 contract, the Company did not see the need to contract for 8,300 dth/d (4,700 plus 3,600) or 7,600 dth/d (4,700 plus 2,900) each month during the year and had

the baseload and peaking components separated. The Company wanted to avoid creating excess capacity during the non-winter months when that capacity was not needed.

Q. How did the termination of the Egyptian storage contract factor into the decision relating to the peaking service?

A. In anticipation of the termination of the Egyptian contract, the Company increased baseload quantities of 1,850 dth/d in the November 2003 contract to 4,700 dth/day in the November 2004 contract. While the Company believed that it had sufficient storage capabilities after the termination of the Egyptian contract, the Company still needed to replace a portion of the Egyptian service to meet design day requirements. Prior to the decision to terminate the Egyptian service, the Company was able to withdraw approximately 5,000 dth/d from the Ellis and Wiseman fields. At 5,000 dth/d, the Ellis and Wiseman fields represented approximately 50% of the Harrisburg operating area's design day requirements. The Company believed that storage of approximately 50% was more than sufficient within a diversified portfolio. The Company prefers a diversified portfolio to assist in mitigating price fluctuations. The Company believes that a diversified portfolio is achieved through a combination of storage, financial hedges and market purchases.

The following table illustrates how the Company's elimination of Egyptian and utilizing a sculpted peaking service saved money for the ratepayers:

2004/2005 Contract:	$33,670/month	12 months	$404,040
Egyptian Storage Demand	$15,000/month	5 months	$75,000
Total Supply Demand Costs			$479,040

2005/2006 Contract:	$19,066/month	12 months	$228,792
	$28,234/month	5 months	$141,170
Total Supply Demand Costs			$369,962

The difference is a demand cost savings to ratepayers in the amount of $109,078.

It should also be noted that since November 2004 the Company has been paying AEM less for capacity than it would have holding capacity and paying TETCO for it directly. The AEM cost has been $4.0566 per dekatherm ($19,066 devided by 4700 Dth and 8300 Dth divided into $33,607) as opposed to TETCO's FT service rate of $4.256 per dekatherm.

Q. Are the costs associated with the peaking service reasonable?

A. Yes. First, the peaking service was awarded through a competitive bidding process that complies with the Commission's rules. The bid process determines the market value for the service because no vendor knows how many other vendors will be submitting proposals. The confidentiality of the process creates an unknown in terms of competition which ultimately yields competitive pricing. Since the Company was paying market value for the service, the associated costs must be reasonable. Second, neither the vendor nor the Company knew when the peaking service would be needed. As a result, the vendor must have the capacity available every day throughout the winter period.

As mentioned earlier, the Company sculpted its RFP to match seasonal demands. As a direct result, costs were less and customers saved money. The RFP letter clearly states how bids are to be submitted, that no bids will be opened before the deadline and that any bids received after the deadline will be returned unopened. The RFP letter also clearly states that "During the RFP process, Atmos will not entertain any individual meetings

with Proposers relating to this RFP until such time that the RFP has been awarded." The RFP letter clearly demonstrates that there are no negotiations allowed throughout the process which ultimately protects the Company and its customers.

Q. Is any adjustment proposed relating to the peaking service?

A. Yes. Staff proposes a disallowance of $56,468 for 2005 relating to the peaking service. This recommendation is based upon the Staff's conclusion that the 55 cent commodity adder is meant to cover the Company's peaking requirements and that the Company did not offer an explanation for the price increase. As already stated previously, the Company again points to its RFP process. The supply was awarded through the competitive bid process and the process determined the market rate. Initially, the Company attempted to theorize the increase being tied to Hurricanes Katrina and Rita since the natural gas market was in disarray at the time, but the Company does not have discussions with vendors once bids are received unless clarification is needed. Other than with respect to clarifying the base load pricing options, the Company did not seek any additional clarification with respect to the Harrisburg bid since the bid was transparent. As mentioned earlier, the Company is hopeful that having multiple RFPs in the future will generate multiple bids for supply.

VI. CONTRACT ELEMENTS

Q. Once AEM submitted the winning bid for the 2005-06 season, did the Company enter a written agreement with AEM?

A. Yes. The parties entered in an addendum agreement, which is attached hereto as Exhibit MM-R-9. This was an addendum to an already existing NAESB base supply contract between the parties, a copy of which is attached hereto as Exhibit MM-R-10.

Q. Does the AEM contract specifically permit buybacks?

A. There is no specific buyback language in the contract and this may be an example where the contract needs more specific language. However, this is merely an administrative oversight because AEM permits buybacks from the Company.

Q. Please explain the purpose of buybacks.

A. Buybacks permit the Company to sell excess gas back to AEM. For example, if the Company's supply nomination at Galatia on a particular day was for 3000 dekatherms, but the Company's system was only able to take 2800 dekatherms, then AEM will "buy back" the additional 200 dekatherms. As explained earlier in my testimony, the Company cannot use storage to keep the TETCO system balanced and incremental sales and buybacks are the only means to do so. Buybacks would be needed no matter what vendor provided the city-gate delivered service. In fact, the Company's agreement with another vendor, Duke Energy, for the Harrisburg supply season of 2002-03 included a buyback provision.

Q. Why did the Company use the ETX point as the pricing point for buyback volumes?

A. The Company used the ETX point for buybacks since that is the point where the baseload purchases occurred. Buy back volumes were excess baseload volumes the Company could not take into its system, so the Company deemed it reasonable to sell the gas back to AEM at the point that it was purchased.

Q. Did the contract with AEM permit changes to first of the month (FOM) nominations?

A. The contract does not specifically allow for changes to first of the month nominations. This is another example of the contract not containing specific language that it perhaps

could otherwise have contained. Even though the contract did not specifically address this issue, AEM allowed the Company to adjust first of the month nominations to keep the system whole. These changes were needed since if the Company, not AEM, caused the imbalance, then it was the Company's responsibility to work off the imbalance. If the Company had not worked off the imbalance, then a penalty and/or overrun situation on the TETCO system may have occurred.

In fact, the procedure implemented by the Company and AEM is entirely consistent with Section 4.3 of the Contract, which provides:

> *The parties shall use commercially reasonable efforts to avoid imposition of any Imbalance Charges. If Buyer or Seller receives an invoice from a Transporter that includes Imbalance Charges, the parties shall determine the validity as well as the cause of such Imbalance Charges. AEM will be responsible for all penalties, imbalance charges and imbalance volumes that result from deviation between the ATMOS nomination made to AEM and those made by AEM. ATMOS will be responsible for all penalties, imbalance charges, and imbalance volumes that result from deviations between the nominations given to AEM by ATMOS and ATMOS' receipt volumes.*

If the Company received more or less gas into its Harrisburg system than it actually nominated to AEM for city gate delivery, then an imbalance on the TETCO system would have resulted and the Company would have been contractually responsible for reimbursing AEM, as the TETCO shipper, for any resulting imbalance fees assessed by TETCO. By allowing the Company to change its nominations intra-month, AEM enabled the Company to avoid the pipeline imbalance charges that would have otherwise resulted. In other words, the parties used commercially reasonable efforts to avoid imbalances and any resulting pipeline penalties and charges.

Q. Do actual deliveries have to be altered in order to address an imbalance?

A. No. An imbalance occurs when nominations do not match physical burns. It is quite simple to work off an imbalance by adjusting nominations instead of altering actual flow. It is not AEM's responsibility to balance deliveries to the Harrisburg city gate when imbalances are caused by the Company. The Company only contracted with AEM for a city-gate delivered service and the accompanying supply. This is not an asset management arrangement. Under an asset management arrangement, the agent is responsible for keeping the system balanced. AEM is not the Company's agent for the Harrisburg system. The RFP letter clearly outlined the services that the Company was seeking and asset management was not one of those services inasmuch as the Company does not hold any firm capacity for Harrisburg that needs to be managed. AEM fulfilled the terms of the contract and is not responsible for balancing the system under these circumstances.

Q. Did the contract with AEM implement a new procedure of splitting of nominations between Harrisburg and Galatia?

A. No. As I previously discussed in my testimony, the Company has always had separate nominations for both Harrisburg and Galatia. It was also stated in the capacity contracts we once held that there were two distinct receipt meters. Moreover, in the contract addendum with AEM for the 2004/2005 season, both the Harrisburg and Galatia meters are designated as nomination points. The same holds true for the contract addendum with AEM for the 2003/2004 season.

Q. Is any adjustment recommended by Staff relating to matters you have discussed in this section of your testimony?

A. Yes. Staff proposes a disallowance of $87,808.13 relating to buybacks, intra-month changes to FOM nominations and splitting nominations between Harrisburg and Galatia.

As mentioned above, the Company made reasonable and valid decisions in regards to items not specifically outlined in the contract, but by no means did the Company do anything imprudent or to directly benefit its affiliate, AEM. Each item listed above was needed to keep the system balanced and those prevented any overrun and/or penalty situation.

VII. CONCLUSION

Q. What is the objective of this testimony?

A. The objective of this testimony is to clear up any misunderstandings and fill in any gaps in information created by the Company's responses to the ICC Staff's data requests. It has been and continues to be the Company's objective to answer all of the Staff's questions directly and unambiguously. This testimony is meant to address the issues that the Staff brought up in its direct testimony. The Company wants to work with the Staff to arrive at an understanding regarding the issues that Mr. Anderson and Mr. Reardon have brought up in their direct testimony.

Q. Does this complete your rebuttal testimony?

A. Yes.

STATE OF TENNESSEE)
)
COUNTY OF WILLIAMSON)

I, Mark A. Martin, being first duly sworn, state that I am the Manager, Regional Gas Supply Operations of Atmos Energy Corporation, that I am authorized to testify on behalf of Atmos Energy Corporation in the subject docket, that the Prepared Rebuttal Testimony of Mark A. Martin attached to this affidavit is true and correct to the best of my knowledge, information and belief.

Mark A. Martin

Sworn and subscribed before me this 29 day of May, 2007.

Notary Public

My Commission Expires: MY COMMISSION EXPIRES November 24, 2008